Technology specific remuneration for capacity to ensure generation adequacy

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Abstract:

Conventional generation units suffer from insufficient revenues from electricity markets. Insufficient revenues can be caused by market distortion. Together with reduced operating hours due to increased renewable energy sources (RES) feed-in, insufficient revenues can lead to unprofitability of generation units. Capacity remuneration mechanisms (CRMs) are discussed to compensate for this distortion and provide supplementary revenue streams. This remuneration is not based on the production of the generation unit but on the availability, i.e. the installed capacity. Long term investment decisions depend on the revenues of the generation unit and are therefore influenced either negative or positive by market distortion respectively supplementary revenue streams. A model is presented to investigate the effects of CRM on the installed capacity to compensate for insufficient revenues due to distorted electricity prices. The model consists of a mixed complementarity problem (MCP) and a linear program (LP). The output of the model shows the generation unit's behavior in terms of increased or decreased installed capacity as response to achievable revenues. Outcomes in systems with different levels and unit-specific CRMs are compared. Resulting installed capacities and occurring load shed are analyzed in a test system with four conventional generation units.

Keywords:

Capacity Remuneration Mechanism, Energy Market, Market-Equilibrium Model, Mixed Complementarity Problem

1 Introduction

In current wholesale electricity markets, generators rely on the revenues from selling electricity to cover their variable costs. Inframarginal rents are used to recover their fixed costs. Market distortions and changing system conditions may result in insufficient revenues that can lead to unprofitability and uncertainties about the future operation. As a consequence absent investment to replace terminating generation capacity and coping with future growth put a threat on system adequacy and security of supply.

Furthermore, the large integration of RES which are in most markets are offered at very low or zero marginal costs have negative influence on the operating hours and revenues of conventional generation units. If electricity markets lack high price spikes in hours of scarcity the market fails to give incentives for new investment in generation units but also for existing units to stay in the market. In literature the absence of revenues from price spikes is discussed as missing money problem, e.g. in Cramton and Stoft (2006), Joskow (2006).

The unavailability of installed capacity in times of scarcity due to absent market signals limits the generation adequacy in the long term, hence endangers the system adequacy as a whole (ENTSO-E, 2012). Generation adequacy includes the ability of a system to serve peak load and also having the flexibility to follow the residual load profile (EURELECTRIC, 2006). In the short term operation, generation inadequacy can lead to constraint security of supply resulting in shed load.

To avoid generation inadequacy and to address the missing money problem, CRMs are widely discussed (Finon and Pignon (2008), Batlle and Pérez-Arriaga (2008), De Vries (2007), Roques (2008)). CRM as policy instrument for ensuring an adequate level of electricity generation capacity are discussed as additional and complementary mechanism (De Vries and Ramirez Ospina, 2012). Through remuneration of installed capacity, CRM create a revenue stream that is independent from the actual output but values the availability of a generation unit. On the long term, the remuneration replaces incentives from price spikes to invest in new capacity and ensures profitability. However, differing levels of remuneration can have influence on the behaviour of the operators which might result in undesired outcome such as inefficient overpayment or creating inequality of opportunity.

Differing designs of CRMs are present in electricity markets and described in e.g. De Vries (2004), Höschle et al. (2013). Neglecting the concrete implementation, this paper only assumes a mechanism to be in place that results in remuneration per installed capacity expressed in €/MW.

This paper is organized as follows. Section 2 introduces the market equilibrium model. The two steps of the model including the MCP and the LP are outlined and the mathematical formulation is presented. Section 3 introduces the examined scenario applied on the model. The results of the scenario are analyzed in section 4. The final section concludes the model description and the scenario results.

2 Model Description

In this section the model is outlined. The purpose of the model is to examine the power generator decisions under changing market condition. The decision to increase the available generation capacity, i.e. to invest, or to decrease, i.e. dismantle existing capacity, is based on the profitability of power generators and consequently their decision to stay in the market. Therefore two model steps are implemented. First, a MCP represents a non-distorted optimal case. In the second step a LP is used to research effects of market distortions and a implemented MCP. In what follows endogenous model variables are typeset lower case while exogenous model parameters are typeset upper case.

2.1 Modeling Assumptions

The market model presented is an electricity equilibrium model focusing on the objective of power generators to maximize their profits. The power generators are modeled as price takers in a perfect competition environment assuming none of the generators uses market power (Gabriel et al., 2013). In general, a complementarity model in a single-commodity market with profit-maximizing, price-taking generators is formulated (Hobbs and Helman, 2003).

The model covers a time span of four periods with each the same number of hourly time steps $t \in T$. The first period represents the initial state of the system with a given generation mix. The consecutive three periods represent states of the market after an investment period. Hence, three investment decision are taken in the time steps $t_{inv} \in T_{inv}$. The investment step can be understood as time leap during which power generators adapt their capacity to the market with e.g. demand growth or increased generation from RES. During each period a demand (DEM_t) and RES (RES_t) profile with an hourly temporal resolution is used. The length of each time period, i.e. the number of time steps can be adapted to a representative time period of one investment period.

It is important to note that technical representation of the generation units are limited because binary variables are avoided. The exclusion of binary variables is required for a model formulation as MCP. As a consequence the model does not include technical specifications like minimal up and down time or startup costs. This leads to an underestimation of the electricity price.

2.2 The Power Generator's Problem

The model describes the behaviour of each individual power generator $i \in I$ in the electricity market. Each power generator has the objective to maximize its profit (1). The power generator decides on the level of generated electricity on the short term ($gen_{i,t}$) and the level of installed capacity on the long term ($cap_{i,t}$). The capacity can be changed ($cap^{+}_{i,t}$, $cap^{-}_{i,t}$) during distinct time steps $t_{inv} \in T_{inv} \subset T$ in the model. The net profit is described by the difference of revenues and costs summed over all time steps $t \in T$. The revenues origin from the sum of selling the generated electricity at market clearing price ($\lambda_t * gen_{i,t}$) and additional revenues from a payment per capacity ($CRM_{i,t} * cap_{i,t}$). The costs consist of the variable cost for generation ($VC_i * gen_{i,t}$) and the fixed costs of installed capacity ($FC_i * cap_{i,t}$). Variable costs include resources, maintenance and operation of the plant. The fixed costs consist of annualized investment costs. Both, fixed costs and payments for capacity are broken down to hourly values assuming an equal spread to fit the model. The generation of electricity is constrained by the installed capacity (2) and the ability to ramp (3), (4). Ramping conditions are excluded during time steps of investment to prevent distortion of the investment decision. Finally, the installed capacity depends on the increase respectively the reduction during investment periods (5). In all other periods the installed capacity equals the capacity of the previous capacity. The dual variable for each equation is given in the brackets.

$$\max \sum_{t}^{T} \Bigg[\lambda_t * gen_{i,t} + CRM_{i,t} * cap_{i,t} - VC_i * gen_{i,t} - FC_i * cap_{i,t} \Bigg] \tag{1}$$

$$gen_{i,t} \leq cap_{i,t} \qquad \forall t \in T \qquad (\mu_{i,t} \geq 0) \tag{2}$$

$$gen_{i,t} \leq gen_{i,t-1} + RAMP_i^+ * cap_{i,t} \qquad \forall t \in T \backslash (\{1\} \cup T_{inv}) \qquad (\rho_{i,t}^+ \geq 0) \tag{3}$$

$$gen_{i,t} \geq gen_{i,t-1} - RAMP_i^- * cap_{i,t} \qquad \forall t \in T \backslash (\{1\} \cup T_{inv}) \qquad (\rho_{i,t}^- \geq 0) \tag{4}$$

$$cap_{i,t} = cap_{i,t-1} + cap_{i,t}^+ - cap_{i,t}^- \qquad \forall t \in T \qquad (\beta_{i,t} \in \mathbb{R}) \tag{5}$$

$$gen_{i,t}, cap_{i,t}, cap_{i,t}^+, cap_{i,t}^- \geq 0 \qquad \forall t \in T$$

2.3 Step I: Mixed complementarity problem (MCP)

For the formulation of the MCP the Karush-Kuhn-Tucker (KKT) conditions are derived. As price taker, the price (λ_t) is exogenous for the power generator which leads to a convex objective function (Gabriel et al., 2005). The convex objective function and the affine inequalities and equalities of the problem above lead to KKT conditions that are necessary and sufficient for optimality (Norcedal and Wright, 2006), (Bazaraa et al., 2006). The conditions are shown in (6) to (13).

$$0 \leq -\lambda_t + VC_i + \mu_{i,t} + \rho_{i,t}^+ - \rho_{i,t+1}^+ - \rho_{i,t}^- + \rho_{i,t+1}^- \perp gen_{i,t} \geq 0 \qquad t \in T \tag{6}$$

$$0 \leq -CRM_{i,t} + FC_i - \mu_{i,t} - RAMP_i^+ * \rho_{i,t}^+ - RAMP_i^- * \rho_{i,t}^- - \beta_{i,t} + \beta_{i,t+1} \perp cap_{i,t} \geq 0 \qquad t \in T \tag{7}$$

$$0 \leq -\beta_{i,t} \perp cap_{i,t}^+ \geq 0 \qquad \forall t \in T \tag{8}$$

$$0 \leq \beta_{i,t} \perp cap_{i,t}^- \geq 0 \qquad \forall t \in T \tag{9}$$

$$0 \leq -gen_{i,t} + cap_{i,t} \perp \mu_{i,t} \geq 0 \qquad \forall t \in T \tag{10}$$

$$0 \leq -gen_{i,t} + gen_{i,t-1} + RAMP_i^+ * cap_{i,t} \perp \rho_{i,t}^+ \geq 0 \qquad \forall t \in T \backslash (\{1\} \cup T_{inv}) \tag{11}$$

$$0 \leq gen_{i,t} - gen_{i,t-1} + RAMP_i^- * cap_{i,t} \perp \rho_{i,t}^- \geq 0 \qquad \forall t \in T \backslash (\{1\} \cup T_{inv}) \tag{12}$$

$$0 = cap_{i,t} - cap_{i,t-1} - cap_{i,t}^+ + cap_{i,t}^- \qquad \beta_{i,t} \in \mathbb{R} \qquad \forall t \in T \tag{13}$$

Assuming perfect competition, the bids of each power generator, i.e. its offer to the market, are based on the variable costs. As a first result, we see from equation (6) that the bids of power generators for generation partly depend on the variable costs. Moreover, the bids are influenced by the shadow prices of the ramping constraints ($\rho^+_{i,t}, \rho^-_{i,t}$) and the capacity limitation ($\mu_{i,t}$). The shadow prices differ from zero if the related constraints are binding. If the capacity is larger than zero, the shadow price of capacity ($\mu_{i,t}$) depends on the fixed costs for capacity but also on the revenues from capacity remuneration (7). Hence, the level of capacity remuneration will have influence on the expected offer.

In this perfect competition framework all power generators offer all electricity to the central market which is represent by the market clearing condition (14). The condition ensures that in each time step the inelastic demand (DEM_t) is covered by the RES feed in (RES_t) and the sum of all generation of the power generators $i \in I$. The exogenous RES feed-in has priority dispatch and cannot be curtailed. The electricity price results from the free dual variable (λ_t). The price can be either positive or negative.

$$\sum_i^I gen_{i,t} + RES_t = DEM_t \qquad \forall t \in T \qquad (\lambda_t \in \mathbb{R}) \tag{14}$$

Together with the market clearing condition (14), the model is a square MCP as there is one condition for each primal and dual variable (Hobbs and Helman, 2003).

2.4 Step II: Linear program (LP)

The second steps adapts the model from the first step. Each power generator still maximizes its profit under the same constraints (2)-(5). However, the price is not endogenous anymore but consists of a modulation of the resulting electricity price profile from step I and is introduced as parameter P_t. As a result, the model can be formulated as a LP with the following objective function for each power generator (15). An unchanged price profile ($P_t = \lambda_t$) leads to the same result as the MCP.

$$\max \sum_t^T \Big[P_t * gen_{i,t} + CRM_{i,t} * cap_{i,t} - VC_i * gen_{i,t} - FC_i * cap_{i,t} \Big] \tag{15}$$

In order to research the effect of insufficient revenues from the electricity sales at the market the price profile from step I is modulated. The lack of revenues is modeled and triggered by an implicit price cap (P_{cap}) (16). The ϵ is introduced to avoid indifferent situation for power generators which could lead to load shed only due to the character of the model. The ϵ is chosen small enough to ensure negliable impact on the revenues result.

$$P_t = \min\{P_{cap}, \lambda_t + \epsilon\} \qquad \text{with} \qquad \epsilon = 0.0001 \tag{16}$$

To allow the power generators to change their behaviour, the market clearing condition is adapted with load shed (ls_t). Load shed ensures the market clearing if power generator generate less electricity than demanded but comes with no additional costs for the power generators (17).

$$\sum_i^I gen_{i,t} + ls_t + RES_t = DEM_t \qquad \forall t \in T \qquad (\lambda_t \in \mathbb{R}) \tag{17}$$

The solution of the LP shows the response of power generators to the modulated price and the introduced payment per capacity. The comparison of the levels of installed capacity in the LP and the MCP gives insights on the efficiency of additional remuneration of capacity to compensate for insufficient electricity prices. Moreover, the occurring load shed indicate threats to the security of supply due to inadequate installed capacity or withheld capacity in time of too low prices.

Both, the MCP and LP model are written in GAMS (GAMS, 2013). For solving the MCP the PATH MCP solver (Dirkse and Ferris, 1995) is used. The LP is solved with the ILOG CPLEX solver (CPLEX, 2013).

3 Scenario

The following section sets the baseline for the scenario discussion. It describes the input data and gives case description. The reasoning for the implicit price cap is given.

3.1 Input Data

For the scenario, four time periods are used. Each time period consists of a sequence of 30 consecutive days with each 24 time steps. In total, this adds up to 2880 time steps $T = \{1, \ldots, 2880\}$. Each power generator decides about increasing or decreasing its capacity after each of the first three periods $T_{inv} = \{721, 1441, 2161\}$. For all other time steps $t \in T \backslash T_{inv}$, capacity cannot be changed, thus $cap^{+}_{i,t}$ and $cap^{-}_{i,t}$ are fixed to zero. The time periods represents a longer time period in reality that can be understood as the time between investment decisions. All costs and revenues are scaled accordingly.

For each time period the demand profile (DEM_t) is based on Belgian data (ELIA, 2013). Fig. 1 shows the profile in the initial state. For the consecutive time periods a demand growth of +2% is assumed following the forecast of ENTSO-E (2012). Note that the steps in between time periods do not necessarily represent yearly steps. The demand in the initial state fluctuates between a peak demand of 12.59 GW and a base demand 8.02 GW. In the last period, the peak demand rises to 13.35 GW. The demand in all time periods is assumed price inelastic and therefore fixed.

The exogenous RES profile (RES_t) origins from the same data and is nominated for an assumed installed capacity of 2 000 MW solar and 2 500 MW wind. For the consecutive time periods a proportional growth of installed capacity of +10% is assumed (additional 450 MW). The intermittent feed-in from RES varies between 2.72 GW and 0.11 GW. This results in a residual load ranging from 5.92 GW to 12.17 GW in the first time period. Because of the increase of demand and RES, the residual load varies from 5.66 GW and 12.83 GW in the last period. With respect to the total consumption, the generation from RES takes a share of 9.24% in the first period and rises to 11.33% in last period.

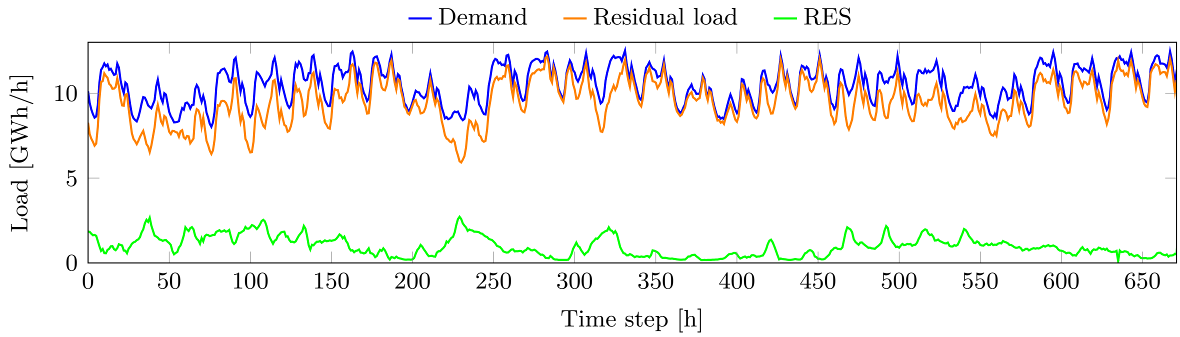


Figure 1: Input Profiles for 1 time period (30 days)

The initial installed capacity of the power generators in the first time period is based on the generation mix comparable to the situations today. Table 1 summarizes the input data for the generation mix. Four different generation units are introduced $I = \{1, \ldots, 4\}$ grouped by technology. In the initial state a total capacity of 12.6 GW is installed, a slight overcapacity compared to the peak demand.

Two base technologies (Unit$_1$ & Unit$_2$) make up for 10 GW. The peak demand is covered

Table 1: Technologies and scenario setup

Unit$_i$ [#]	VC_i [€/MWh]	FC_i [(€/MW)/h]	CAP_i [MW]	$RAMP_i^+$ [%/h]	$RAMP_i^-$ [%/h]	Possible increase	Possible decrease
1	6.00	39.80	6500	0.083	0.083	✓	✓
2	35.00	11.40	3500	0.200	0.200	✓	✓
3	50.00	4.56	1800	0.500	0.500	✓	✓
4	72.00	2.85	800	1.000	1.000	✓	✓

by the peak units (Unit$_3$ & Unit$_4$). The generation units are distinguished by their technical and economical characteristics. The economical characteristics include the variable and fixed costs. The fixed costs (FC_i) represent the annualized investments costs over the lifetime of a power plant. The variable costs are the cost of operation and maintenances, including costs for resources and emissions. The values are based on De Jonghe et al. (2011).

The ramping rates (upwards & downwards) express the flexibility of each unit. The peak units are more flexible than the base units. For example, Unit$_1$ needs 12 hours to ramp from 0 to 100% while Unit$_4$ is able to ramp to 100% within 1 time step.

The possible increase or decrease is used to adapt the scenario to the regulatory framework. The social acceptance and legislation can be expressed in the chosen values to possible increase or decrease capacity. Moreover, certain scenarios like a nuclear phase out can be implementing by fixing values for capacity increase respectively decrease ($cap_{i,t}^+$, $cap_{i,t}^-$) in the model setup.

Demand response is not considered in the generation mix. RES is already introduced through the RES profile.

3.2 Description

In order to allow the impact of remuneration for capacity a lack of revenues has to be introduced. Compared to the optimal reference case (MCP) in which the price can rise to any level, a price cap is introduced. An obvious price cap is the market cap. However, due to interventions of regulators and cautious bidding behaviour of power generators price seen at the market hardly rise above a certain level. This can be seen as an implicit price cap. The price cap (p_{cap}) is set artificial but corresponds with the prices seen at the Belgian power exchange Belpex (Belpex, 2013). This price cap is chosen below the maximum price of the MCP. The maximum price occurs once as optimal price spike in each time period after an investment decision. Fig. 2 shows the price profile in which the price spikes per investment period are cut.

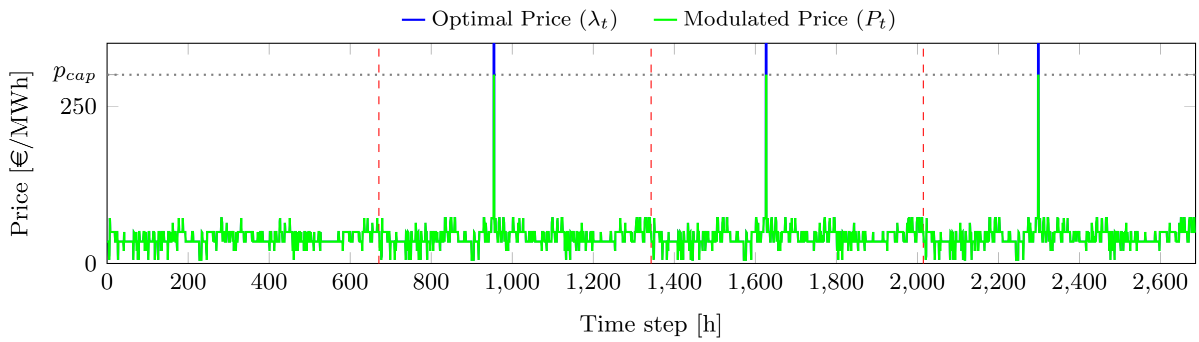


Figure 2: Optimal Price (MCP) & Modulated Price (LP)

Missing revenues from the price spike lead to a situation in which generation units step out of the market. In order to replace the revenues from the price spike in the second model step (LP) the remuneration for capacity is introduced ($CRM_{i,t} > 0$). In order to achieve the same level of generation in a time period as in the optimal case, thus no load shedding, all revenues have to be replaced equally in that time period. The missing revenues can be expressed by the difference of price spike and price cap times the generation of the unit in this time step ($(\lambda_t^{max} - p_{cap}) * gen_{i,t}$). Additional revenues for capacity can be expressed as the sum of payments over all time steps of the current time period times the actual installed capacity ($\sum_t (CRM_{i,t} * cap_{i,t}) = T/4 * CRM_{i,t} * cap_{i,t}$). The optimal level of payment can be derived as shown in (18).

$$CRM_{i,t} = \frac{(\lambda_t^{max} - p_{cap}) * gen_{i,t}}{T * cap_{i,t}} \tag{18}$$

Assuming that in the time step when the price spike occurs, the generation unit is operating at the capacity limit ($gen_{i,t} = cap_{i,t}$), the formula simplifies to (19). Moreover, the price spike is the price for generating one more unit in times of scarcity which includes the fixed costs and variable costs of one more unit of the peak unit (Unit$_{peak}$) (20). In a long-term perspective ($T \rightarrow \infty$), the optimal remuneration should be the fixed costs of an additional unit of the peak unit (21).

$$CRM_{i,t} = \frac{(\lambda_t^{max} - p_{cap})}{T} \tag{19}$$

$$= \frac{FC_{peak} * T + VC_{peak} - p_{cap}}{T} \tag{20}$$

$$\lim_{T \to \infty} CRM_{i,t} = FC_{peak} \tag{21}$$

Assuming an annual estimation ($T = 8760$) of the level of $CRM_{i,t}$, a value that is below the FC_{peak} is already optimal. Depending on the price cap and the variable costs of the peak unit, a reduction of the CRM can be considered (22).

$$\left[1 - \frac{\frac{FC_{peak}*T+VC_{peak}-p_{cap}}{T}}{FC_{peak}}\right] * 100 \qquad [\%] \tag{22}$$

Applied on the cost structure of the peak unit (Unit_4), the optimal value for the $CRM_{i,t}$ in the model is 2.51 (€/MW)/h which is 11.9% below the fixed cost FC_4.

$$\left[1 - \frac{2.51}{2.85}\right] * 100 = 11.9 \qquad [\%] \tag{23}$$

In general, the level of $CRM_{i,t}$ should be equal for all units as all units are producing in the time of peak demand at their limit. The level, however, only depends on the cost structure of the peak unit. Unit- or technology-depending remuneration always favors units that receive above the optimal levels and may results in shifts of the installed capacity of each unit. Moreover, the optimal level is independent of the peak demand or the feed-in of RES as long as the cost structure of the peak unit stays unchanged respectively the peak unit changes. However, the generation mix changes with the resulting residual demand.

4 Results

In this section the results of the scenarios based on the findings of the description are shown. Three cases are compared to show the effects of different levels of capacity remuneration. A case with too high capacity remuneration as well as a case with differing remuneration per technology is compared with the optimal reference case. Table 3 concludes the results.

4.1 Case I: Reference case

In the reference, case the additional capacity remuneration is calculated based on the equation (20) discussed in the previous section. The capacity remuneration is equal for all units. It results in a payment of 2.5107 (€/MW)/h, or 21994 (€/MW)/a. Applying this level of capacity remuneration results in the optimal case as MCP. Consequently, no load shed applies and all units can cover both variable and fixed costs respectively have a profit of zero. Hereby varies the share of revenues originating from the capacity remuneration between 5.48% for Unit_1 and

53.33% for Unit_4. This corresponds with the expectation as the base units mostly generate their revenues from inframarginal rents while peak units mostly rely on price spikes which are replaced by the CRM. The total cost for the society adds up to 947.81 M€. Table 3.I shows the resulting capacity installed by the end of the forth period.

4.2 Case II: Overpayment

In the second case an increased payment for capacity is applied. The level of payment equals the fix cost of the peak unit, i.e. 2.85 (€/MW)/h, or 24966 (€/MW)/a. Again, it is the same for every unit. The result is similar to the result of the reference case. No load shed appears as all units stay in the market and produce in the same way as in the optimal case. With the overpayment per installed capacity, the revenues for each generation unit are larger than its total cost resulting in a profit for each generation unit. Consequently, this also results in a higher total cost for society (see Table 3.II). Note, that the overpayment does not lead to an increased installation of capacity, i.e. building up a security margin. The revenues from CRM for capacity are still below or equal to the fixed costs so that investment in unused capacity stays inefficient.

4.3 Case III: Unit_1 is overpaid

The third case differs from the previous cases as the capacity remuneration is not equal for all units. While Unit_2 to Unit_4 receive the optimal payment of 2.5107 (€/MW)/h, Unit_1 receives an arbitrary higher payment of 2.65 (€/MW)/h, or 23214 (€/MW)/a. An overpayment of the base technology leads to a shift of installed capacity and also generation. Figure 3 shows the reaction of the system to the unbalanced payment. Unit_1 becomes economically more interesting compared to the other units and increases its capacity and generation. Unit_2, the competing unit in the base and mid load units, reduces the capacity and the generation. The total installed capacity is equal to the other cases, i.e. the total remuneration for capacity is the same. The absent generation is partly replaced by Unit_3, although not to its full extent.

Figure 4 visualizes the results of the third case. For every unit, the corresponding subfigure shows how the unit covers its fixed costs respectively makes profit. The blue graph shows the sorted cumulated inframarginal rents and revenues from the CRM over the last three time periods. A positive slope represents selling electricity at a higher price than the variable costs. A negative slope indicates that the unit has to generate electricity in times of prices below variable costs due to insufficient flexibility. The capacity remuneration is also displayed separately (green graph). To compare with the optimal result of the MCP the dotted blue graph shows the cumulated inframarginal rents without the CRM and price cap. The difference between the full and dotted lines indicates the shifts resulting from adapted capacity. While for the optimal case the dotted and full lines are equal, the graphs differ in the third case for all units. Unit_1 has higher rents which results in a slight profit despite the increased fixed costs due to increased capacity. To put it another way, over the whole time, the cumulated inframarginal rents are higher than the fixed costs. For all other units the cumulated inframarginal rents rise to the adapted fixed costs meaning that the profits equal zero.

Table 3: Comparison of Case Results

Case	Total Cost for Society *[M€]*	Load shed *[%]*	$cap_{1,T}$ $\sum gen_{1,t}$ Profit_1	$cap_{2,T}$ $\sum gen_{2,t}$ Profit_2	$cap_{3,T}$ $\sum gen_{3,t}$ Profit_3	$cap_{4,T}$ $\sum gen_{4,t}$ Profit_4	*[GW]* *[GWh]* *[M€]*
I	947.81	0.00	6.40 12965.99 0.00	3.74 5753.48 0.00	1.73 917.73 0.00	0.96 47.77 0.00	
II	956.43	0.00	6.40 12965.99 4.40	3.74 5753.48 2.44	1.73 917.73 1.15	0.96 47.77 0.63	
III	1064.39	0.20	6.64 13353.18 1.84	3.02 5027.21 0.00	2.20 1217.62 0.00	0.97 48.27 0.00	

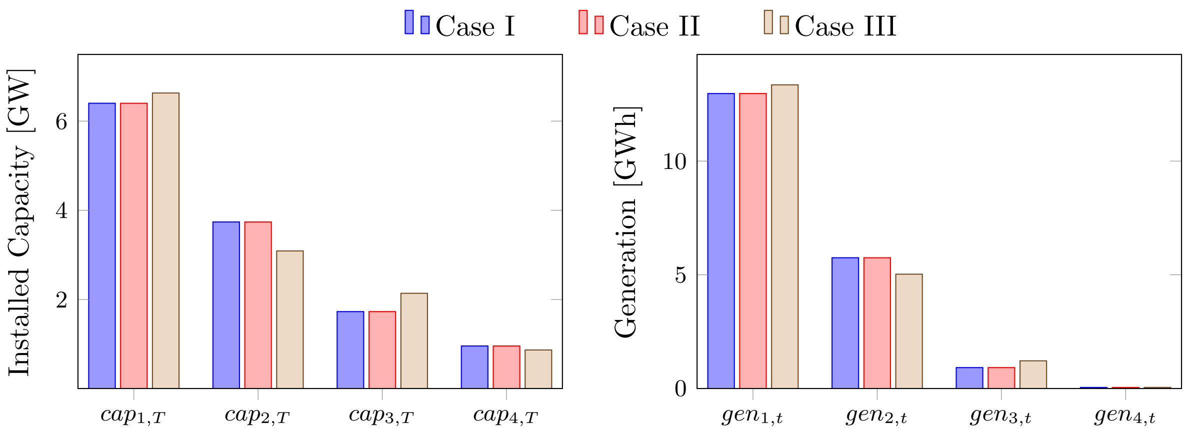
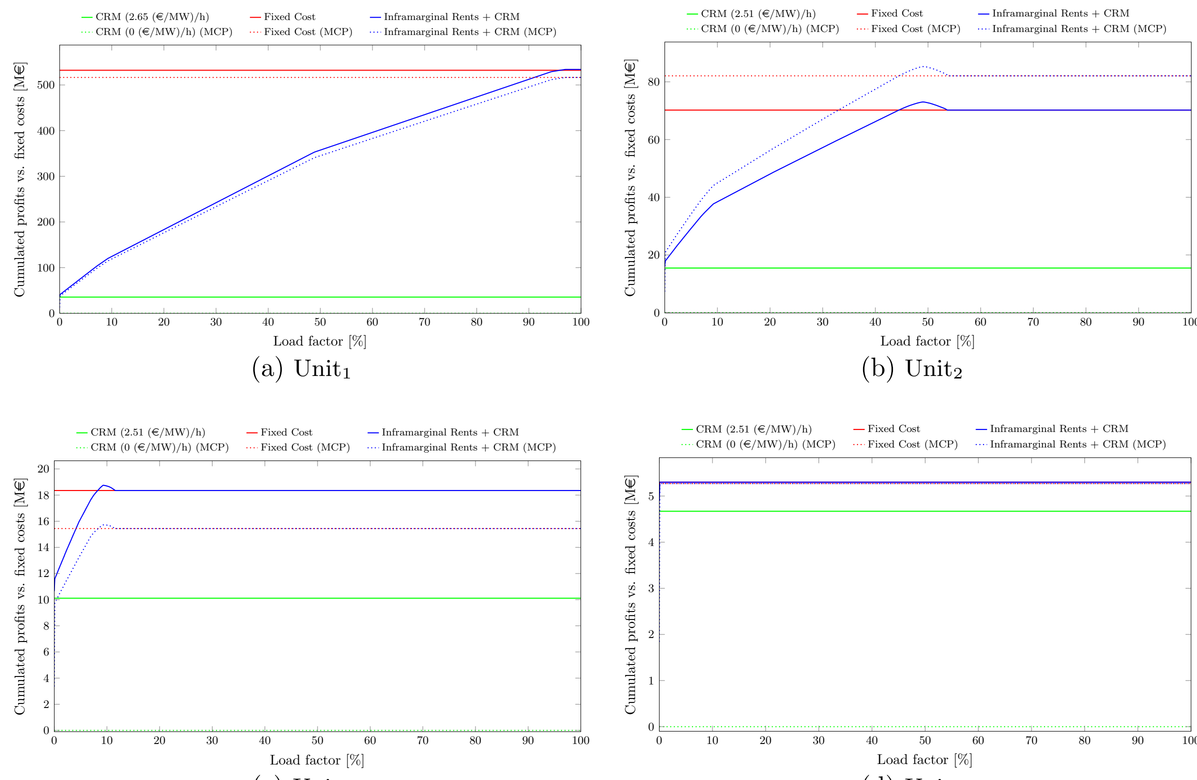


Figure 3: Comparison of installed capacity and total generation per unit and case

A share of 0.2% of the total generation is not served by the generation units resulting in shed load. This is because the installed capacity differs and the prices are not high enough to trigger generation. Assuming the load shed implies a cost to the society equal to the market cap price 3000€/MWh, the total cost for society rises to 1064.39 M€ (see Table 3.III).



(a) Unit_1 (b) Unit_2

(c) Unit_3 (d) Unit_4

Figure 4: Cumulated profits in comparison to fixed costs

5 Conclusions

The model allows for insights on how generation units react on insufficient revenues from the electricity market. Moreover, it shows how different levels of capacity remuneration to compensate for absent price spikes influence their behavior. The estimation of the level of capacity remuneration is crucial for the outcome for the system.

The model is applied on a test system with four units each representing a technology with distinguishing economic and technical characteristics. Within four time periods of each 28 days, each technology adapts its capacity in 3 consecutive investment steps to the developing demand and RES feed-in. The decision is based on the revenues from selling electricity and the revenues origin from the capacity remuneration mechanism (CRM).

The implicit price cap in the linear program (LP) is replaced by capacity remuneration. The level of the remuneration depends on the cost structure of the peak unit. On the long run, the CRM should be equal to the fixed costs of the peak unit to cover all costs. Considering shorter time periods, the optimal level is derived based on the implicit price cap as well as the variable and fixed costs of the peak unit. An increased payment above the optimal level but below the fixed does not lead to increased capacity in the system. Unequal payment leads to shift in the generation mix, i.e. the installed capacity of the units, which eventually causes undesired side effects, e.g. load shed.

Further development of the model includes the optimization of the system operator behavior. Instead of setting the level of CRM as a model parameter, the system operator sets the incentive for the generation units based on his own optimization. A price-based CRM respectively a volume based CRM can be modeled by deciding on either the level of payment or the minimum level of installed capacity in the system.

Acknowledgment

Hanspeter Höschle holds a PhD fellowship of the Research Foundation - Flanders (FWO) and the Flemish Institute for Technological Research (VITO).

Nomenclature

$i \in I$	Index of power unit	*[-]*
$t \in T$	Index of time step	*[-]*
$t_{inv} \in T_{inv}$	Index of time step with a possible investment	*[-]*
$gen_{i,t} \geq 0$	Generation of unit i in time step t	*[MWh]*
$cap_{i,t} \geq 0$	Installed capacity of unit i in time step t	*[MW]*
$cap^{+}_{i,t} \geq 0$	Added capacity of unit i in time step t	*[MW]*
$cap^{-}_{i,t} \geq 0$	Reduced capacity of unit i in time step t	*[MW]*
$ls_t \geq 0$	Load shedding in time step t (LP only)	*[MWh]*
$\lambda_t \in \mathbb{R}$	Dual variable of market clearing	*[€/MWh]*
$\mu_{i,t} \geq 0$	Dual variable of capacity constraint	*[€/MW]*
$\rho^{+}_{i,t} \geq 0$	Dual variable of ramping constraint (upwards)	*[€/MW]*
$\rho^{-}_{i,t} \geq 0$	Dual variable of ramping constraint (downwards)	*[€/MW]*
$\beta_{i,t} \in \mathbb{R}$	Dual variable of capacity preservation	*[€/MW]*
VC_i	Variable cost of unit i	*[€/MWh]*
FC_i	Fixed cost of unit i	*[€/MW]*
$CAP_i = cap_{i,0}$	Initial installed capacity of unit i	*[MW]*
$RAMP^{+}_i$	Upwards rampability of unit i	*[%/h]*

$RAMP_i^-$	Downwards rampability of unit i	*[%/h]*
DEM_t	Demand in time step t	*[MW]*
RES_t	RES in time step t	*[MW]*
$CRM_{i,t}$	CRM for unit i in time step t	*[€/MW]*
P_t	Price for electricity in time step t (LP only)	*[€/MWh]*

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